COMMONWEALTH OF MASSACHUSETTS
before the
DEPARTMENT OF PUBLIC UTILITIES

Notice of Inquiry/Rulemaking Establishing The Procedures To Be Followed In Electric Industry Restructuring By Electric Companies	)))))	**D.P.U. 96-100**

COMMENTS OF THE ATTORNEY GENERAL

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TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. OVERVIEW 1

III. STRANDED COST RECOVERY 3

IV. SPECIAL TREATMENT FOR CERTAIN GENERATION 7

V. PERFORMANCE BASED REGULATION 9
- A. The Performance Based Ratemaking Scheme in the Proposed Rules Allows the Utilities to Be and Rewards Them for Being the High Cost Distribution Service Providers in the Nation 9
- B. The Performance Based Ratemaking Scheme in the Proposed Rules Cannot Deny Parties Rights To Petition A Review Of A Utility's Rates For Reasonableness . 11
- C. The Performance Based Ratemaking Scheme in the Proposed Rules Must Include Earnings Sharing 12
- D. The Performance Base Ratemaking Scheme in the Proposed Rules Must Include a Sales Growth Adjustment 13

VI. CORPORATE STRUCTURE 14

VII. AFFILIATE TRANSACTION RULES OF CONDUCT 15

VIII. CONSUMER PROTECTION: REGULATION OF LOAD AGGREGATORS AND SUPPLIERS 16

IX. DISTRIBUTION FRANCHISE 19

X. BASIC, “STANDARD OFFER” AND UNIVERSAL SERVICE 20

XI. THE BOSTON EDISON PLAN 22

XII. SMALL CUSTOMER ISSUES 31

XIII. ENVIRONMENTAL ISSUES 33
A. AIR EMISSIONS 33
B. ENERGY EFFICIENCY 38
1. Retrofit Market Barriers 39
2. Distribution Planning and Energy Efficiency 39
3. Low Income Energy Efficiency 40
4. Rate Design and Energy Conservation 40
C. RENEWABLES 41

XIV. CONCLUSION 44

. INTRODUCTION

The Attorney General hereby files his Comments and Alternative Rules to the Department of Public Utilities' ("Department" or "DPU") May 1, 1996 Explanatory Statement and Proposed Rules ("May 1, 1996 Order") in the matter of D.P.U. 96-100 (Notice of Inquiry / Rulemaking, pursuant to 220 C.M.R. §§ 2.00 et seq., establishing the procedures to be followed in electric industry restructuring by electric companies subject to G.L. c. 164). He also hereby files Suggested Hearing Questions and his Request to Present Oral Testimony.

. OVERVIEW

The Attorney General appreciates this opportunity to provide comments on the Department's explanatory statement and proposed rules. While the Attorney General agrees with several of the Department's proposals in its explanatory statement and proposed rules, he is alarmed that the debate to date has not focussed on what the primary objective of restructuring must be, *i.e.* to provide timely rate relief to all Massachusetts consumers and businesses from electric prices that are now nearly twice the national average. The Attorney General believes that the following five principles should go a long way toward achieving the goal of timely rate relief: restructuring should result in much lower prices; the benefits of restructuring should be made available to all consumers; a restructured utility industry must continue to protect the environment and promote conservation; restructuring should ensure some measure of affordability for low-income consumers; and the transition to a fully functioning, stable and reliable restructured market for electric power must be monitored closely. While the Department does address the latter three principles, there is no provision for the first two principles discussed above. That is, there is no assurance that there will, in fact, be **meaningfully lower prices** and **benefits** available to **all** consumers.

In fact, under the Department's May 1 explanatory statement and proposed rules, consumers would bear cost of utility stranded investments and be exposed to the risk of higher prices and/or that larger customers might benefit to the detriment of smaller customers. Utility shareholders, who had a choice about where to invest their money, are all but assured of a virtual risk-free transition to a restructured electric industry, while smaller consumers, who had no choice about what utility would serve their region, are stuck assuming the shareholder's investment risk: the risk of their utility's past imprudent investments in strandable generation assets and the potential risk that larger customers will be granted rate relief on their backs.

In this current round of Comments the Attorney General has not addressed many of the issues pending at this. Many, such as the creation and role of an independent system operator ("ISO"), a Power Exchange, transmission, and horizontal market power, have already been addressed in the Attorney General's earlier submissions. The Hartman & Tabors report, *The Market for Power in New England: The Competitive Implications of Restructuring*, also addresses many of these issues. Others, the Attorney General believes will be addressed adequately by other parties and will be the subject of final comments after review of other material submitted today as well as information adduced at the hearings. The Attorney General's comments here will focus on issues that appear to have not received sufficient attention in the Department's May 1, 1996 Explanatory Statement and proposed rules - namely issues that deal with consumers.

. STRANDED COST RECOVERY

In D.P.U. 95-30, the Department indicated that it was "concerned that a move to full competition without making a provision for some measure of stranded cost recovery could provoke costly, reform-delaying litigation" and that "[d]elay and litigation uncertainty are clearly not in the public interest." *Electric Utility Restructuring*, D.P.U. 95-30, p. 36. Notwithstanding these indications, however, the Department was also quite clear in its determination that "it is uncertain whether Massachusetts electric utilities have any legal entitlement to stranded cost recovery." D.P.U. 95-30, Appendix B, p. 14. Thus, while the Department did state a policy in favor of "transitional stranded cost recovery," it indicated that this policy was to guide "settlement" negotiations and that it could not decide the outcome of any "individual adjudications of stranded cost claims that could become necessary." D.P.U. 95-30, p. 36.

The Attorney General believes that the Department changed course in its May 1 order. The Department's vision and rules have the effect of resolving, without any hearing, the legal and factual issues in the utilities' favor. Moreover, the Department's pronouncements reveal expectations that are well below the task at hand. In particular, the Department's order and subsequent public statements by Commissioners clearly envision a non-bypassable charge that is subject only to the woefully inadequate constraint that it not result in rate increases. The stranded cost recovery mechanism is designed to provide a full return of and on stranded costs, the utilities' claims for which were considered to be, "at best, uncertain" only nine months ago. Thus, in marked contrast to the striking and unambiguous need to provide immediate rate relief to the citizens and businesses of the Commonwealth, the Department appears to envision and approve of a restructuring that will likely provide little more than a ten year rate freeze.[1]

The Attorney General submits that the Department should change course. He continues to maintain that there is no legal right to protection from market forces and no reliable empirical basis

[1]Given the Department's proposed Performance Based Ratemaking regime it is likely that there will be ten years of annual rate increases and not a freeze.

for any “strandable cost” recovery claim. As the Department noted in D.P.U. 95-30, Appendix B

> [t]here are two parts to the legal analysis of stranded cost recovery: (1) an analysis of whether Massachusetts electric utilities have been granted exclusive franchise rights and the implications of franchise rights for recovery of stranded costs; and (2) an analysis of whether and when Constitutional provisions against takings could be implicated by regulatory changes being considered by the Department.

D.P.U. 95-30, Appendix B, p. 3. In regards to the first issue, the exclusivity of the franchise, the New Hampshire Supreme Court has recently determined that Public Service Company of New Hampshire does not have an exclusive franchise. *Appeal of Public Service Company of New Hampshire*, 1996 WL 264662 (May 13, 1996). There is no reason whatsoever to expect that a different conclusion would be reached under Massachusetts law. Indeed, as the Attorney General has argued before, the law in Massachusetts is, if anything, more clear than that in New Hampshire.[2] Moreover, irrespective of the lack of legal support for the notion of an exclusive franchise, the accompanying study by Hartman and Tabors, *The Regulatory Compact And Its Relevance To Stranded Assets Under Restructuring: A Modest Proposal*, should put to rest any argument that exclusivity is the result of some “regulatory compact.”

In regards to the "takings" issue, it has clearly been decided that the due process clause does not insure values or require restoration of values that have been lost by the operation of economic forces. *Market Street Railway Company v. Railroad Commission of California*, 324 U.S. 548

[2] The public franchise granted to an electric utility is "the right to manufacture and supply [electricity] for a particular locality and to exercise special rights and privileges in the streets and elsewhere which are essential to the proper performance of its public duty and the gain of its private emoluments and without which it could not exist successfully." *Attorney General v. Haverhill Gas Light Company*, 215 Mass. 394, 399 (1913). However, the utility "enjoys these privileges as licensee and without any paramount or exclusive right therein . . . ." *Id.* at 402. The franchise is neither a contract nor property, and the holder of the franchise acquires no vested rights in it. *Boston Real Estate Board v. Department of Public Utilities*, 334 Mass. at 488-491; *Roberto v. Department of Public Utilities*, 262 Mass. 583, 587 (1928). The franchise is subject to a considerable degree of legislative control and regulation under the authority of the Legislature to exercise police power in deciding who may have special privileges in the public ways, and under the power of amendment, alteration or repeal of corporate charters. *Attorney General v. Haverhill Gas Light Company*, 215 Mass. at 402; *Boston Real Estate Board v. Department of Public Utilities*, 334 Mass. at 489. It is subject to the Department's continuing power to amend in the public interest. *Holyoke Street Railway Company v. Department of Public Utilities*, 347 Mass. 440, 445 (1964).

(1945). Moreover, even if their were some legal or factual basis for the claim of some "entitlement" to protection from market forces, an independent report by Resource Insight (which was submitted with the Attorney General's April Comments) suggests that there is no reason to believe that deregulation will result in utility generating assets being worth less rather than more than they are today. *Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities* (April 1996).

The disparity in current generation costs inherent in various Massachusetts utility rates is unambiguous proof that some utilities have been better than others in running their businesses. It is incredible that the Department suggests that utilities should bear no responsibility for the results of their decisions. The utilities have long asserted their discretion to run their companies, and consumers must not be required to pay: they had no voice in the way the utility was operated and therefore, should not be forced to bear the entire risk. Therefore, to the extent that the Department affords utilities any automatic recovery to avoid litigation, it should make it clear that that is its discretionary policy decision, not any requirement of law, and should limit any such recovery to no more than $0.005/kWh.

In any event, the Department should require market valuations of generating assets.[3] The Attorney General submits that no stranded costs should be awarded unless a utility either divests itself of its generating assets or provides an equivalent market derived measure of the value of its generating plants. Real numbers must be used - not estimates. Only if an actual market

[3] The Department's proposed true-up provisions of its administrative approach will likely accomplish little more than to guarantee that customers will overpay, by as much as 150%, of a utility's actual stranded costs. The proposed rules require a presentation at intervals of two, five and ten years of the differences between the projections and actual experience. The true up proposal has an intrinsic bias to overstate the amount of stranded costs because the utility gets to keep part of its overestimation. The proposed rules do not even try to get to the right number. Instead, the Department proposes to sets rates based on some projection and then reconcile back to a bandwidth and not back to the actual number. The utility then gets to keep a portion of its overestimation.

determination demonstrates that value of all the utility's generating related assets,[4] taken in their entirety, is less than their book value should any recovery be considered and, then, only after netting out the increased value of the remaining distribution and transmission assets. No utility in Massachusetts has established that it will in fact have stranded costs. The Department's proposed rules would merely institutionalize the existing high rates for another decade and institute a series of annual rate increases for companies who historically have had excessive earnings.[5]

A sale or some other reliable market valuation of the value of a utility's generating assets is the only reasonable approach. While the Department has indicated that it has fears "that a hasty divesture of generation assets may have an adverse impact on costs to customers," D.P.U. 96-100, p. 56, that should not preclude conditioning consideration of any stranded cost claim on a market determination. First, it is not at all clear that a single large sale of all utility generation assets would indeed be considered a "fire sale" and result in "fire sale" prices. In fact, it may be that a well organized but comprehensive auction of those properties is the means to the highest prices. *See* Wilson, Auctions of Stranded Assets (filed herewith). In any event, so long as the Department changes its course from its current ill-considered 100 percent recovery, utilities would have appropriate incentives to avoid fire sale prices -- unlike the actual operation of the present system which got us into the current state of affairs, actually forcing utilities to bear the consequences of their actions will likely lead to reasonable behavior.

. SPECIAL TREATMENT FOR CERTAIN GENERATION

The Department has raised questions whether recognition should be given to the unique

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[4] In its stranded cost recovery mechanism, the Department focuses just on a utility's generating plants and not its generating assets. Plant held for future use, such as potential generating sites, over funded pension plans and insurance reserves all have a value in excess of their book value but the Department does not net this value against the assumed losses from actual generating facilities. All generating assets must be included in a stranded cost recovery mechanism, not just those that have an arguably negative value.

[5] Massachusetts utilities have out performed industrial company even though as regulated companies they face lower risks. *See* Attorney General's April 12 Comments, Attachment A, Historical Holding Period Returns for Utilities and Industrial Averages.

circumstances of nuclear power plants. The Attorney General has in the past acknowledged that providing adequate funding for the decommissioning of nuclear power plants is an important public safety matter and must be considered separately. Beyond that, it is not clear whether any particular special treatment should be given to these plants. The earlier Resource Insight study suggests strongly that some of these units are now and likely will remain uneconomic to operate. These "unique" circumstances, notwithstanding the fact that they may have billion dollar implications, do not suggest that any special treatment is required. The Department should not be lulled into continued acceptance of the utilities argument that the units need to be operated because they have so much invested. If the revenue that these units will generate is not sufficient to cover the cost of their operation, they should be shut down; you cannot "make it up on the volume" if your are not covering out of pocket costs. However, the Department should not dismiss the possibility that the actual operation of these units will improve if the utilities are forced to bear the billion dollar implications of their past decisions: necessity is the mother of invention.[6]

It is, however, important to note here that the Department's proposal makes no attempt to address the "strandable cost" implications posed by non-utility and exempt wholesale generator contracts. As explained in his earlier comments, the Attorney General does believe that special treatment of these contracts is necessary if the Department is to fulfill its obligation to protect the interest of the public. Absent the approach recommended by the Attorney General, sellers under such contracts will have no incentive to renegotiate exorbitant contract charges and will be the only entities to move into the restructured world while retaining all of the benefits they enjoyed under the current regime. Moreover, to the extent that the Department remains committed to "full recovery" surcharges, those sellers will for some time to come be the only real beneficiaries of restructuring, an outcome that the Attorney General believes to be profoundly disturbing.

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[6] Assuming the NRC continues to perform its responsibilities, the operators of nuclear power plants will continue to have strong incentives to comply with necessary safety regulations. Moreover, it appears that at least some believe that there are reasonable prospects for significant improvements in the performance of nuclear power plants. *See* Appendix 2.

. PERFORMANCE BASED REGULATION

A. The Performance Based Ratemaking Scheme in the Proposed Rules Allows the Utilities to Be and Rewards Them for Being the High Cost Distribution Service Providers in the Nation

> The underlying cause of high prices is the framework, by which I mean the market structure and the planning process. We will forfeit an opportunity, *we will fail to position our region competitively against other regions and nations*, if we do not move aggressively to implement a truly open and competitive electric industry structure. [Emphasis added.]

"Prepared Remarks to the Northeast Energy & Commerce Association" John B. Howe, January 24, 1996.

The Department's efforts to make the electric industry more efficient and competitive should not start and end with its restructuring of the generation business. Stopping with the generation business will give the ratepayers at best half a loaf. To bring the full benefits of an efficient and competitive electric industry to Massachusetts consumers, the Department must also reduce distribution service rates.

The Department has proposed to move forward with Performance Based Ratemaking ("PBR") for distribution service in this docket. In whatever methodology that the Department chooses to base its performance based ratemaking scheme, it must consider and correct for the enormous difference between Massachusetts electric utilities distribution rates and those in the rest of the United States.[7] The Attorney General continues to recommend use of an unadjusted national cost per kWh benchmark for the PBR formula with a sharing of the cost savings associated with any movement towards the average. *See* Attorney General's April Comments, pp. 13-14. First, it will provide incentives for the companies to be more competitive on a national basis. Second, this

[7] The average Massachusetts utility's cost for distribution service is more than 50 percent higher than the national average. *See Massachusetts Electric Company*, D.P.U. 96-25, Testimony of Jose A. Rotger, page 6.

formula will ensure that the inflation and productivity intrinsic in the price movements will be those of the electric distribution industry and not some poor attempt at an artificial recreation or simulation.

In contrast, a Price Cap mechanism that simply provides for industry price changes and industry productivity is guaranteed to be no more than an entitlement program for Massachusetts monopoly electric utilities.[8] Although the Price Cap mechanism may incent better cost controls, the Department's proposal will allow the utilities to keep savings they achieve in reducing their "going in" costs. This will prevent any real progress on the high rate level while rewarding the utilities for past inefficiencies.

The Department proposes to include only an Accumulated Inefficiencies adder to the productivity factor in its Price Cap rules to eliminate Regulated Electric Utility Inefficiencies. This will not, by itself, make Massachusetts distribution companies competitive. A specific adjustment must be made to the PBR formula to eliminate this Massachusetts inefficiency. If the Department were to make an adjustment to its proposed Price Cap formula for the Massachusetts difference, an adjustment of two percent per year in terms of a productivity factor offset will still not make the utilities competitive for more than *twenty years*.[9] Thus, notwithstanding the Attorney General's argument that bench marking is the best performance based ratemaking alternative at this time, if the Department continues to believe that a Price Cap mechanism is appropriate, then the Department should begin with the Accumulated Industry Inefficiencies offset of one percent, and the stretch factor of one percent that it found appropriate in *NYNEX*, D.P.U. 94-50 (pp. 166-168) and add to those amounts the additional Accumulated Massachusetts Inefficiency offset of at least two percent

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[8] Only after the Massachusetts distributions companies have brought their costs in line with the rest of the industry should any price cap mechanism be implemented, since only then will the costs and productivity be comparable to those industry averages used for the price and productivity indexes. And only then should the utilities be able to earn extra profits for being truly more productive then the rest of the industry.

[9] The twenty-year period can be determined by the following formula:

$$(1 + 0.02)^{20} = 1.52$$

to push the companies in the direction of the national average.

B. The Performance Based Ratemaking Scheme in the Proposed Rules Cannot Deny Parties Rights To Petition A Review Of A Utility's Rates For Reasonableness

The rules as currently proposed exempt the utilities from challenges to, or review of their earnings based on cost of service regulation during the term of the plan of no less than five years. Proposed Rule 220 CMR 11.04 (8). This section of the rules is in conflict with the General Laws of Massachusetts. The Attorney General and others have the right under the General Laws to petition the Department for a review of a utility's rates:

> On written complaint of the attorney general, of the mayor of a city or the selectmen of a town where a gas or electric company is operated, or of twenty customers thereof, either as to the quality or price of the gas or electricity sold and delivered, the department shall notify said company by leaving at its office a copy of such complaint, and shall thereupon, after notice, give a public hearing to such complainant and said company, and after such hearing may order any reduction or change in the price or prices of gas or electricity or an improvement in the quality thereof, and a report of such proceedings and the result thereof shall be included in the report required by section seventy-seven.

Mass. G.L. c.164, § 93. The Department has no inherent authority to issue regulations or promulgate rules or regulations that conflict with statutes or exceed authority conferred by statutes by which it was created. *See Massachusetts Hospital Association, et al. v. Department of Medical Security et al.,* 412 Mass. 340 (1992); *Bureau of Old Age Assistance of Natick v. Commissioner of Public Welfare*, 326 Mass. 121 (1950). Therefore, this section of the Department's proposed rules must be deleted or significantly changed to remove the prohibition against rate reviews by such interested parties.

The availability of rate reviews during the term of a price cap plan will follow Department precedent. The Department provided no prohibition to earnings reviews in the NYNEX Price Cap case, D.P.U. 94-50. There is no reason and no basis for such prohibition in this case. Therefore, the Department should follow its own precedent and allow rate reviews during the term of any price cap plan.

C. The Performance Based Ratemaking Scheme in the Proposed Rules Must Include Earnings Sharing

One method to greatly decrease the possibility of parties petitioning the Department to review a utility's rates for reasonableness is to require Earnings Sharing in the PBR approach. The Restructuring Rules should include a PBR section that requires the utilities to share earnings. A reasonable approach to the earnings sharing mechanism is to provide a one-hundred basis point dead band for all earnings greater than the allowed rate of return on common equity. A fifty-fifty ratepayer/shareholder sharing of earnings above the dead band would be in effect for all earnings up to 600 basis points above the allowed rate of return. All earnings more than 600 basis points above the allowed rate of return would be returned 100 percent to the ratepayers. This mechanism, while not establishing the optimum rates, will at least recognize that whatever rules and rates are established as a result of this rulemaking will probably be incorrect and will thus provide for some balancing to bring them back in line. Therefore, an Earnings Sharing mechanism should be included in the PBR rules, since it will provide some assurance to regulators and ratepayers alike that any PBR scheme has reasonable bounds on the rates and incentives that result.

D. The Performance Base Ratemaking Scheme in the Proposed Rules Must Include a Sales Growth Adjustment

The Department should include a growth adjustment to the Price Cap formula, if it decides that a Price Cap is the best PBR scheme for the distribution service utility business. The proposed restructuring of the electric industry in Massachusetts will deregulate the generation part of the business so that demand for distribution services will become dependent on the sales efforts of the many marketers. Future sales growth will no longer be simply a function of the economy and the monopoly utility's nominal efforts. Sales growth will come from energy marketers efforts to scour the state trying to find new customers and new uses for their services, as well as the increased demand as a result of the lower energy supply prices they will bring. Under the Price Cap plan in the proposed rules, the distribution company receives all the benefits of future growth through higher revenues and earnings. This benefit will not be derived from improved productivity, but rather simply from the monopoly service provider's economies of scale as a result of increased sales due to the efforts of the marketers.

Any price cap formula should ensure that the benefits of sales growth flow annually to the ratepayers in terms of rate reductions. A simple methodology to incorporate this is to divide the Price Cap formula by one plus the growth rate in sales:

` $$P = (I - X + Z) / (1 + g)$$

This formula will properly flow back the benefits of sales growth to the customers where they belong. Therefore, the Department should add this factor to the proposed Price Cap Rules to flow the effects of sales growth back to the ratepayers.

. CORPORATE STRUCTURE

The Department believes it is necessary for electric companies, who could potentially favor their affiliates in a restructured electric industry, to modify their corporate structure in order for regulation of the supply function to be lifted. D.P.U. 96-100, p. 25. The options for modifying their corporate structure range from creating separate functional divisions within a corporation to corporate divestiture. *Id.,* p. 26. The Department continues to believe that mandatory divestiture of generation or any other category of assets is not desirable or necessary at this time. D.P.U. 96-100, pp. 26-27; *citing*, D.P.U. 95-30, p. 24. However, the Department nevertheless believes that voluntary divestiture of generation over time provides the cleanest solution to the problem of inappropriate and anti-competitive affiliate transactions, and that a post-divestiture market structure characterized by arms-length transactions among generators, the ISO, and distribution companies is apt to require the least regulatory supervision. *Id.,* p. 27. While the Attorney General agrees with the Department that the functional separation of generation from transmission and distribution services is the minimum acceptable approach, as stated in his earlier comments, he does not however believe that "generation divestiture is absolutely necessary to address vertical market power concerns". Attorney General Comments, D.P.U. 96-100, April 18, 1996, pp. 4-5. Instead, the Attorney General submits that such vertical market power concerns must be addressed through some affiliate "code of conduct." *Id.,* p. 5. The Department expects that corporate restructuring, coupled with realistic, enforceable ground rules regarding affiliate transactions, can in large measure guard against market power abuse.

. AFFILIATE TRANSACTION RULES OF CONDUCT

The Department proposes to adopt rules that prevent preferential treatment among affiliates in applying tariffs, disseminating information, and offering services. D.P.U. 96-100, p. 27. The Attorney General agrees that there must be a standard of conduct governing the relationship between affiliates of what is now the vertically integrated utility but believes that said standard must go further than what has been set forth by the Department in its proposed rules. Therefore, in addition to the rules proposed by the Department in 220 CMR 11.06 (*See,* DPU 96-100, Attachment A, pp. A.17-A.18), the Attorney General also proposes the following rules be added under 220 CMR 11.06(3) which should address any other concerns that may arise in transactions between affiliates:

(j) A distribution company and its affiliates must conduct operations at arms length.

(k) A distribution company shall not promote the sales of its affiliates. A distribution company shall not provide leads to marketing affiliates and shall refrain from giving any appearance that the distribution company speaks on behalf of its affiliate. Nor shall the affiliate trade upon, promote or advertise its affiliate or suggest that it receives preferential treatment as a result of its affiliation. If a customer requests information about marketers, a distribution company should provide a list of all marketers operating on the system, including the affiliate, but should not promote its affiliate.

(l) A distribution company shall not disclose any proprietary customer information to its affiliates.

(m) Material violations of these regulations will result in a prohibition of affiliate from dealing with distribution company's end users in its service territory.

(n) A distribution company must strictly enforce a tariff provision for which there is no discretion in the application of the provision.

(o) A distribution company shall not condition or tie any agreements to release transmission capacity to any agreement by a supplier, customer or other third party relating to any services in which their marketing affiliates are involved.

(p) A distribution company shall not disclose to its affiliates any information which it receives from (I) a non-affiliated customer or supplier; (ii) a potential customer or supplier, (iii) any agent of such customer or potential customer, or (iv) a marketer or other entity seeking to supply power to a customer or potential customer.

(q) If a distribution company offers its affiliate, or a customer of its affiliate, a discount, rebate or fee waiver for transmission services, meters or meter installation, standby service or any other service, it must contemporaneously offer the same discount, rebate or fee waiver to all similarly situated non-affiliated suppliers or customers and must file with the Department procedures that will enable the Department to determine how the distribution company is complying with this standard.

See, Re: Standards of Conduct for Local Distribution Companies and Their Gas Marketing Affiliates, 167 P.U.R. 4th 237 (N.J.B.P.U., 1996); *Consolidated Edison Company of New York, Inc.,* Case 95-G-0759, Comments of Enron Capital & Trade Resources Corp., October 27, 1995, pp. 2-7.

. CONSUMER PROTECTION: REGULATION OF LOAD AGGREGATORS AND SUPPLIERS

In its May 1 order, the Department proposed regulations that would establish registration requirements for entities seeking to do business with end users in Massachusetts, Draft Rules, § 11.07, but requested comments on whether the proposed requirements were sufficient or should be expanded to include additional indicators of financial and managerial ability, or the posting of surety bonds. As discussed below, the Attorney General submits the proposed registration requirements are not adequate to protect the public. The Department must amend its proposed regulations to require a certificate as a condition of doing business in Massachusetts and should condition the continuing possession of such a certificate on adherence to a comprehensive set of consumer protection rules. Anything less will leave Massachusetts consumers vulnerable to harm from unscrupulous and unreliable entities that may seek to take advantage of consumer inexperience, especially at this time of great change in the industry.

There can be no doubt that the Department has an obligation to the public to insure that consumers are not harmed by entities selling power. As an absolute minimum, then, the Department should require that all entities that make sales to end users provide not only a registration statement, but also condition their ability to do business in the Commonwealth on obtaining a "certificate" based upon some showing of sufficient financial wherewithal to backup a reasonable portion of any commitments that they may make, *i.e.,* a requirement of a bond or other evidence of financial capability to cover any pricing "commitments" made for some period of time. Moreover, the Attorney General submits that at least during the early phases of this entry into a "brave new world", the Department should condition the issuance of any certificate to do business with end users upon a finding that the applicant possesses the managerial, technical, and financial ability to provide the proposed service.[10] *Compare: Satellite Business Systems*, D.P.U. 84-125 (1984); *Allnet Communications Services, Inc.*, D.P.U. 84-177 (1985).

At least during the early years of the transition from the current "regulated" industry structure to one based on a mature, robust and reliable "market", it is imperative that the Department monitor the developing market and retain sufficient authority to act promptly and effectively to protect consumer interests. Thus, the Attorney General believes that the Department should retain "quality" control over entry into this industry (*i.e.*, require certification rather than mere registration) as well as the ability to exclude or expel entities that may harm the public interest.[11] Past experience in the U.S. domestic airline industry as well as the local private pay telephone industry suggest that retaining control over entry need not unnecessarily deter entry nor impair the vigor of competition.[12]

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[10] The Attorney General is mindful of a need to balance a desire to provide protection against unreliable and/or unscrupulous suppliers with the need to encourage vigorous competition and experimentation. In that regard, he suggests that the Department could require a verified application in order to speed up the certification process.

[11] In addition, a certification requirement is also necessary if the Department is to ensure adequate incentives exist for renegotiation by NUGs and EWGs with high cost existing contracts. Given that it now appears that, at least for some companies, the only credible "strandable cost" claims that they can make involve such contracts, the Attorney General submits that this reason alone requires the Department to adopt a certification requirement. Otherwise, such entities, from an industry that has fared quite well under the guise of *force majeure* defenses of their inability to perform in a timely fashion, will, unlike any other interest, consumer or utility, be allowed to reap the benefits of restructuring without surrendering any of the benefits that were obtained from the prior regime.

[12] However, given the Attorney General's experience with the Department's response to complaints concerning violations of its own consumer protection regulations for private pay

Moreover, revokable certificates provide a very effective enforcement tool for the Department to ensure compliance with necessary consumer protection regulations.

Importantly, as was discussed in the Attorney General's April Comments, the Department should include within its restructuring regulations provisions calculated to ease the transition for consumers, minimize confusion and preclude anti-consumer practices. In particular, in addition to modifying existing regulations to conform to the new marketplace (*i.e.*, require the inclusion of a Department telephone number and an explanation of consumer rights on any bills), the Department should promulgate regulations that require, at a minimum: that contract forms be in plain language and be approved by the Department; standard pricing disclosure by all sellers; and conformance to appropriate rules to protect against the "slamming" practices that been the cause of much consumer harm and inconvenience in the telecommunications industry. *See In the Matter of Policies and Rules Concerning Unauthorized Changes of Consumers' Long Distance Carrier*, 10 F.C.C.R. 9560 (1995).

. DISTRIBUTION FRANCHISE

Notwithstanding the fact that the Department has acknowledged that "it is not clear that the utilities have exclusive franchises," D.P.U. 96-100, p. 39; D.P.U. 95-30, Appendix B, p. 9, in its May 1 explanatory statement, the Department suggested that:

> as a matter of general policy, we propose to hold existing distribution service territories intact as we proceed through the transition. We suggest that the most expeditious way of implementing the policies reflected in this explanatory statement is to treat the service territories as exclusive, at least through December 31, 2007.

D.P.U. 96-100, p. 40. The Attorney General submits that it is perfectly clear that public utilities in Massachusetts **do not** have an exclusive franchise[13] and that, in any event, the Department lacks the

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phones, to say nothing of the absence of any Department enforcement of those regulations, it should be observed that the mere existence of entry and consumer protection regulations will not, in and of themselves, provide any assurance that consumer interests will be protected.

[13] The New Hampshire Supreme Court has recently held that New Hampshire utilities do not have exclusive franchises as a matter of law. *Appeal of Public Service Company of New*

authority to expand upon whatever the extent of any exclusivity that may now exist.

First, the law in Massachusetts is clear: the public franchise granted to electric utility is "the right to manufacture and supply [electricity] for a particular locality and to exercise special rights and privileges in the streets and elsewhere which are essential to the proper performance of its public duty and the gain of its private emoluments and without which it could not exist successfully." *Attorney General v. Haverhill Gas Light Company*, 215 Mass. 394, 399 (1913). The utility "enjoys these privileges as licensee and *without any paramount or exclusive right* therein . . . ." *Id.* at 402 (emphasis added). The franchise is neither a contract nor property, and the holder of the franchise acquires no vested rights in it. *Boston Real Estate Board v. Department of Public Utilities*, 334 Mass. at 488-491; *Roberto v. Department of Public Utilities*, 262 Mass. 583, 587 (1928). The franchise is subject to a considerable degree of legislative control and regulation under the authority of the Legislature to exercise police power in deciding who may have special privileges in the public ways, and under the power of amendment, alteration or repeal of corporate charters. *Attorney General v. Haverhill Gas Light Company*, 215 Mass. at 402; *Boston Real Estate Board v. Department of Public Utilities*, 334 Mass. at 489. It is subject to the continuing power to amend in the public interest. *Holyoke Street Railway Company v. Department of Public Utilities*, 347 Mass. 440, 445 (1964).

Second, it should be obvious that without some further legislative action, the Department lacks the statutory authority to create "exclusive" service territories through December 31, 2007. In granting franchises, the public good is determinative. The Department is obligated to change the service territory and even grant competing franchises if it is required by the public interest.[14]

Hampshire, 1996 WL 264662 (May 13, 1996).

[14]G.L. c. 164, §§ 87 through 91, which establish the process by which an electric utility may gain consent from a municipality to serve customers within that municipality, even though another utility may already be supplying electricity there.

. BASIC, "STANDARD OFFER" AND UNIVERSAL SERVICE

In determining the framework into which the Department will restructure the industry, the determinations concerning the organization of basic, "standard offer," and universal service are quite important. Not only will they bear directly on an important interface between the new structure and consumers and on whether the new system continues important protections for low income consumers, but they may also affect the pace of the development of competition. The Attorney General is in general agreement with the determinations reflected in the Department's May 1 proposal.

With regard to the proposed universal service regulations, the Attorney General has two limited comments. First, in order to ensure that entities doing business with end users do not engage in any redlining, he submits that the Department should amend its proposed regulations to put the risk of non-payment of one month of arrears in residential power bills on the distribution company. In the absence of such a requirement, sellers of power may tend to avoid soliciting business from groups of customers perceived to present greater risks of non-payment. Second, he submits that the Department should explore, during the course of the hearings, the advantages and disadvantages of requiring that universal service customers purchase power as part of a pool covered under a contract put out to bid under Department supervision. The Attorney General recognizes that there are competing interests involved -- providing choice to all customers and providing a known competitive rate and making bundles of sales available for potential competitors -- but submits that the Department should solicit and receive views on this variation on its initial proposal.

With regard to basic service, the Attorney General is supportive of the overall thrust of the Department's approach and, subject to the following qualification, believes that the Department's second alternative -- allowing, but overseeing sales from affiliates -- is the better approach. Importantly, however, the Attorney General submits that the preferred form of oversight under this second option is a supervised bidding program whereby all potential suppliers are allowed to submit bids to provide this service. Assuming an effective code of conduct, affiliated sellers should not have any undue advantage.

Finally, in regard to “standard” offer service, the Attorney General submits that the Department should certainly allow utilities to offer, to their existing customers, a “standard offer” service which will closely approximate their current offering, albeit at a lower price. While the Attorney General shares some of the competitive concerns raised by other parties over making this “standard offer” service the “default” choice for customers who do not make any affirmative selection of power supplier, he is also concerned that consumers be afforded a very easy way to elect “standard offer” service in the likely event that they do not wish to make any change in their current service. To this end, he suggests that the Department solicit views during the upcoming hearing on the question of whether such an approach provides the appropriate balance between the interests in encouraging new competition and protecting legitimate consumer desires to remain with their current supplier.

. THE BOSTON EDISON PLAN

In its May 1, 1996 Order, the Department stated that it is committed to ensuring that the transition to a new industry structure proceeds as smoothly as possible for the electricity consumers of the Commonwealth. D.P.U. 96-100, p. 47. The Department stated that the basic concept behind BECo's proposed E-Plan (Phase I) -- implementation of an unbundling/market proxy plan -- may ease the transition to a new market structure by allowing customers to become familiar with an unbundled bill format and with the movement in the cost of electricity in a competitive market. *Id.*, pp. 48-50. Therefore, the Department proposed to require implementation of rate unbundling and energy services as close to January 1, 1997, as possible. *Id.*

BECo's unbundling plan for Phase I of the E-Plan is divided into two components: network services and energy services (market price of energy). BECo Vol. 1, pp. 25, 51-59. Network services would contain distribution, transmission and access charges. *Id.*, p. 49.[15] The New

[15] The initial distribution and transmission rates would be set on 1996 cost and revenue levels. BECo Vol. 1, p. 49. Each succeeding year's revenue level would be set through a price

Performance Adjustment Clause ("NPAC"), fuel charge, and conservative service charge (mandated audit service only) would be eliminated, with the NPAC and conservative service charges placed into the distribution charge, and the fuel charge in the market price of energy. BECo Vol. 2, App. I, 1, p. 6. BECo proposes to make the charge for demand-side management a separate charge. *Id.*

BECo proposed to price energy services based on a proxy New England Regional Market Price Index ("NEMPI"). BECo Vol. 1, pp. 53-59; *See* DPU 96-100, pp. 48-49. The proposed NEMPI is a hourly cent per kWh price comprised of three components: (1) the marginal fuel and variable operating costs of the most expensive unit operating in any hour ("Marginal Energy Cost"); (2) the start-up, shut-down, and no-load costs (fuel costs incurred to keep the unit available) of the most expensive unit running in any hour ("No Load Costs"); and (3) a component measuring the value of capacity taking into consideration the cost to customers of losing power and the probability in any hour of losing power ("Capacity Costs"). *Id.*, p. 55. BECo proposed to calculate this component by multiplying Loss of Load Probability (LOLP)[16] by the Value of Lost Load (VLL).[17] *Id.*

To calculate the NEMPI, BECo proposed using the PROSYM production costing model. *Id.* This model simulates a system's hourly operation using keys inputs such as system load data, generating unit data, and VLL. *Id.*, p. 56. BECo proposed to use a VLL of $6 per kWh. *Id.*[18]

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cap. *Id.* The access charge would contain five components: regulatory assets, decommissioning costs, the above market portion of NUG contracts, utility generation investments, and the cost of generation which may be critical to sustain the transmission support in the region. *Id.*, p. 50.

[16] BECo defines the LOLP as the probability that capacity is inadequate to meet demand in a particular hour because of a sudden unexpected increase in demand or a sudden failure of a generating unit. BECo Vol. 12, p. 55.

[17] BECo defines VLL as the measure of the price that customers are willing to pay to avoid a loss of supply. BECo Vol. 1, p. 55.

[18] Using PROSYM, BECo would project the NEMPI one day ahead, and would calculate an actual NEMPI after-the-fact for each hour. BECo Vol. 1, p. 58. Customers with hourly metering will be charged the actual hourly market price index for all energy consumed during the corresponding hour; for customers without hourly meters, an average of the actual hourly market price indexes during the month or throughout the year will be used. *Id.*, p. 59.

BECo is promoting that NEPEX be the provider of both the projected and actual market price index values. *Id.*, p. 58. This requires NEPOOL Executive Committee approval. *Id.* Until such time as NEPEX or an ISO provides the NEMPI, BECo would create the NEMPI. *Id.* BECo offered to do so even though it does not have the NEPOOL participant actual daily data. *Id.* BECo claimed that its personnel can develop reasonable estimates of actual load, generation, and fuel prices. *Id.*, p. 59.

It is the Attorney General's understanding of the May 1 Order that the Department is endorsing BECo's plan to formulate the market price of energy during the transition, but is not endorsing the specifics of the Company's plan with respect to network services. In its Order, the Department stated that the unbundling of rates, including the cost allocation and design of those rates, must be consistent with its precedent that has evolved over the years. D.P.U. 96-100, pp. 50-52. BECo's proposal to eliminate the NPAC and place it into the distribution charge is contrary to this precedent. Simply, the NPAC is technically a generation component, and does not belong in the distribution charge. *See* Attorney General April Comments, p. 11, n. 10. In addition, consistent with Department precedent, the demand-side management ("DSM") charge should be included in the distribution charge since future DSM programs will be pursued as part of the distribution function. *See Id.*, p. 11. The general point is that the unbundling of rates must be real and distinct: distribution, transmission, and generation costs must be functionally separate.[19]

Further, BECo's network services plan includes an access charge that assumes full recovery of stranded costs without any mitigation. If there are any stranded costs, which the Attorney General maintains there are not, the failure to mitigate such costs when the "bell rings" on January 1, 1997 is contrary to the Order in D.P.U. 96-100 and the accompanying regulations.[20] To interpret the order

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[19] The Attorney General agrees with BECo that the fuel charge should be eliminated. In addition, PPCAs should be eliminated.

[20] As set forth in Section XIV, *infra*, the Attorney General maintains that any claim for stranded costs should be based on an actual market determination, and not the administrative test as outlined in the D.P.U. 96-100 and the proposed regulations.

as not requiring this mitigation during the transition would be inconsistent with the Department's endorsement of the transition principle of "seeking near term rate relief." D.P.U. 96-100, p. 9; *See* D.P.U. 95-30, pp. 30, 44. As BECo has shown, under certain, likely market scenarios, all which assume full recovery of stranded costs without any mitigation, bills will increase. BECo Vol. 2, App. I, 3,a,2. The failure to require mitigation before the transition also would be inconsistent with the Department's commitments of ensuring that the transition to a new industry structure proceeds as smoothly as possible for the electricity consumers of the Commonwealth, and that the transitional period provide substantial educational value to these consumers. D.P.U. 96-100, pp. 47, 50. While these are appropriate goals, bill increases are not the way to ease the transition or provide educational value to consumers in the move to a new industry structure.

If the Department is not going to require mitigation of stranded costs before the transition begins, then BECo's access charge should be called something else during the transition. As demonstrated in the Attorney General's earlier written comments in this proceeding, the "access" charge proposed by BECo for Phase I is much higher than the stranded cost charge that might be justified in full restructuring. In Phase I, BECo will not yet have mitigated stranded costs by divesting or repricing generation at the market price, including the future value of the capacity. Hence, this charge should be called "other generation costs," to avoid confusion with the much lower or negative stranded-cost charge that the Department may later approve.[21]

Further, if the Department is not going to require mitigation of stranded costs before the transition begins, Department should ensure that the bill redesign during the transition be revenue neutral. The proposed BECo Phase I E-plan is not. *See* BECo Vol. 2, App. I; BECo April 12, 1996 Comments, pp. 7-8. In the absence of some true-up mechanism, under Phase I of E-Plan customers

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[21] As the Attorney General stated in his earlier written comments in this docket, the allocation of stranded costs, if any, amongst classes, should be done in a manner similar to the way generation costs are allocated today as approved by the Department in each company's last rate case. *See* Attorney General April Comments, p. 12. In addition, if a stranded cost charge is allowed, it should be labeled as such, collected on an energy basis, and appear separately on bills. *See Id.*, p. 11 and n. 11.

may see a significant risk of price increases and decreases in their bills without the resort to a competitive market. The concept of contracts for differences may not be the solution to this real concern. Some third party, either a power marketer or a financial institution, would have to agree to enter into such deals based on a simulated competitive market. There is no guarantee that this will happen. In addition, not all customers will know that contracts for differences is an option, and compounding the problem is the fact that it is the only option during the transition.

The Department should demand that the redesign be revenue-neutral, prospectively and retrospectively. To ensure retrospective revenue-neutrality, any over- or under-collection could be credited or added to stranded costs.[22] Even with reconciliation, a rate proceeding following each utility's compliance filing may be necessary to determine the initial estimate of market costs, the market-cost proxy, the non-market rate components, the form of the reconciliation, and projected rates and revenues for initial rate design and for the reconciliation.

Turning to the specifics of BECo's computation of NEMPI, BECo calculated a market price of 3.5 cents per kWh for all customer classes, except for the G-3 class where it calculates a market price of 3.4 cents per kWh. BECo Vol. 2, App. I, 2. Generally, these prices are higher than current market prices because they reflect marginal energy costs, no load costs and the value of generating capacity as calculated by BECo. In order to present clear and transparent hourly market price signals to customers during the transition, the simulated market prices must be as accurate and realistic as possible.

One component of BECo's NEMPI that should be adjusted to achieve this goal pertains to capacity costs. BECo calculated the capacity costs using a VLL of $6 per kWh. The VLL should be eliminated or significantly reduced. Given the current capacity surplus in the region, the actual loss of load probability is negligible for the near future. *See* WMECO Industrial Customer Group

[22] BECo proposed that rates be set on, and revenues reconciled to, its projections of rising fuel and purchased power costs. BECo April 12, 1996 Comments, p. 7. Litigating future costs for all seven Massachusetts utilities would take time and resources that the Department and the parties need for the broader restructuring cases. To avoid unnecessary litigation, fuel prices should be included in the reconciliation described *supra*.

Comments, p. 13.

In addition, the capacity cost calculation is based on LOLP, which may or may not be a good approximation for the driving force of hourly or daily capacity prices in the competitive market. Marketers are just as likely to purchase capacity in advance, and charge customers a predetermined adder. The LOLP is a theoretical computation, not subject to empirical verification. There is no particular benefit to including this tangential and contentious variable in the short-term unbundling of utility rates.

BECo also proposed to include in the development of NEMPI an arbitrary charge for "No-Load Costs," computed for an undefined "most expensive" unit on line in any hour.[23] No There are a number of concerns with this charge. First, no load costs are not a part of the market-clearing price. In addition, Boston Edison's method for computing no-load costs can result in extremely high costs in hours in which the "most expensive" unit is operated at a very low level. *See* BECo Vol. 1, p. 64 (hour 18 on 2/6/96). Further, this proposed charge is particularly inappropriate, since the "most expensive" unit will often be coming on line to meet load in subsequent hours (or ramping down after meeting load in earlier hours), so its startup is not determined by load in the current hour.

In its May 1 Order, the Department asked for responses to three separate questions on the transitional phase to a new market structure. D.P.U. 96-100, p. 53. One question is as follows.

> Would implementation of an unbundling/market proxy plan (such as that proposed by BECo) in 1997 by all Massachusetts retail distribution companies significantly change what otherwise would be the dispatch order of generating units in New England? Why? What implications, if any, would this have for the practicality and desirability of implementing this plan? What implications, if any, would this have for the collection and mitigation of stranded costs?

The implementation of an unbundling/market proxy plan such as BECo's Phase I E-Plan should not directly effect the dispatch order of generation units in New England. The NEPOOL rules govern the dispatch order. These rules are based on objective criteria. The end goal is economic dispatch. An unbundling/market proxy plan such as the E-Plan should not change this priority.

[23] In its filing, BECo does not state whether "most expensive" would be computed on the basis of marginal dispatch cost, no-load cost, or some other measure.

However, NEPOOL, nor an unbundling/market proxy plan for the transition has any control over the efficiency of the operation of the generating plants. This is so because there isn't a competitive market and customers have no place to "shop." Contracts for differences does not change this scenario because utilities are guaranteed there estimate of market prices. Therefore, as the march to the new market structure takes hold, there is no incentive for utilities to operate their plants efficiently. Instead, there is an incentive for utilities to operate their plants less efficiently because to do so will inflate the estimate of stranded costs by lessening the potential for mitigation either through sales of the plants or sales of capacity or energy from the plants. This is an outcome that clearly is not in the best interests of ratepayers.

The Department also posed the following question.

> Would an unbundling /market proxy plan in 1997 allow and encourage the development of contracts for differences? Please explain how? How might the design of the plan affect the likelihood that customers would enter into such contracts?

In theory, an unbundling/market proxy plan in place for 1997 would allow the development of contracts for differences. For example, under BECo's E-Plan, BECo would determine the spot market price. If the customer can agree with another party on the level of the future market price, and that each would pay the other any differences from that level of price and the spot market price as determined by BECo, then the parties can enter into that deal. The deal does not affect the deliverability of power. It is simply a game of financial reward and risk based on how well one can predict future spot market prices. However, in reality, a competitive generation market does not exist at this time. BECo's plan is simulation of what the market price may be in competitive market situation. While some third party may want to enter into differences contract with a customer of BECo based on a simulated market price established by BECo, the likelihood of this happening is certainly less than it would be in an environment where market prices are determined by a fully competitive market.

A third question posed by the Department is as follows.

Would an unbundling/market proxy plan in 1997 require the publication of a projected and

> actual NEMPI by NEPEX? What would be the benefits and drawbacks of NEPEX calculating the projected and actual NEMPI? If not done by NEPEX, how would Massachusetts companies develop and publish an equivalent NEMPI on their own?

While the publication of a projected and actual NEMPI by NEPEX is not necessarily required, it is desirable because NEPEX would have access to the NEPOOL participant actual daily data and would represent an existing, central body available to perform this function. In any event, the Department should require an objective index (such as the NEPOOL dispatch margin or a firm-power transaction price) computed by a neutral third party (such as the power exchange, once it exists). If it is not done by NEPEX or some other third party, then the Massachusetts companies would have to pool their resources, using company personnel knowledgeable and active in the New England energy market, to develop the projected and actual NEMPI. Given the differences in market prices as projected in each of the filings for 1998, it is not at all certain that the companies could agree on a common market price for 1997.

. SMALL CUSTOMER ISSUES

An important issue that the Department has apparently overlooked in its May 1 Order pertains to the issue of ensuring that all customers have access to the benefits of the competitive bulk-power market. Large customers will have access to these benefits because they will be, or are already, fitted with real-time meters. For those customers, the distribution company will be able to determine the amount of power that each marketer must deliver to the distribution company in each hour to serve those customers. However, this sophisticated metering has not been installed on any significant number of residential or small commercial customers. At some point in the future, real-time metering will be available and cost-effective for all customers. In the meantime, some mechanism must be developed to ensure that every customer has access to the competitive market. If the Department fails to create such mechanisms in time for marketers to comprehend them and develop rate offerings for small customers by the beginning of restructuring, those customers will be excluded from the benefits of competition.

Therefore, the Department should ensure that at least one of the following mechanisms becomes available to all customers:

(1) Regional Aggregation. A single marketer could serve all customers in a geographical region, such as municipality, or the area served from a substation, feeder, or other convenient metering point, other than those who opt for real-time meters and service from another aggregator.[24] The large customers in the region or area will presumably opt for individual direct access. Smaller customers could do so as well, if they or their marketers are willing to pay for the incremental costs of real-time metering. The remaining customers in each region or area could collectively choose their marketer, either through hearings or polling by their municipal governments, or an agent selected by the Department. The municipality or agent would determine the formula for allocating the regional power cost to individual bills, with Department approval. The marketer's responsibility for power delivery to each regional aggregation could be determined in real time, or with a trivial delay.

(2) Individual Customer Allocation. To increase customer choice and allow individual selection of power marketer, the distribution utility can estimate the hourly loads of each small (not real-time-metered) customer, ex post, by: (a) determining total distribution system load in the hour; (b) subtracting loads of customers with real-time meters, plus estimates of associated losses; (c) allocating the monthly bill of each small customer to hours on the basis of a series of multipliers developed from load-research data, plus losses;[25] and (d) reconciling the results so that the sum of customer loads and losses equals system load.

Appendix 1 provides an example of the form that the hourly multipliers might take. Each utility would need to file the loss factors and hourly allocation multipliers, along with the supporting load-research data and computations, for review and approval by the Department. The marketer's responsibility for power delivery to each customer could only be determined after the fact, when all meters have been read. Initially, this would result in a delay of a month or more between power

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[24] This is the approach required by the New Hampshire Public Utility Commission in current New Hampshire pilot.

[25] Utilities will need to read meters at least monthly for this approach to be at all viable.

delivery and reconciliation, although more frequent meter reading would reduce the lag.

In either the regional aggregation or individual customer allocation approaches described above, all energy delivered to the distributor in each hour will be allocated to small customers or direct-metered customers or to losses. An important issue that needs to be further considered by all parties and resolved by the Department is who will provide or purchase load-shaping, regulation, operating reserves, and other ancillary services. While it may be feasible for the distributor to provide these services, there has not yet been any demonstration that the distributors will be the best providers or that they should be precluded from providing such services.

. ENVIRONMENTAL ISSUES

The Department stated that restructuring should lead to environmental improvement through: 1) reduced power plant emissions; 2) continued gains in energy efficiency; and 3) development of clean renewable resources. D.P.U. 96-100 May 1 DPU Statement, pp. 35-39, 64-70. The Attorney General strongly agrees with the Department that it is important to achieve environmental improvement in all three of these ways as part of electric utility restructuring.

A. AIR EMISSIONS

The Department stated that electric utility restructuring should support and further the goals of environmental regulation, including cleaner air. Id., pp. 35-39. The Department found that there is a compelling need for coordination between the various jurisdictional authorities (DPU, Massachusetts Department of Environmental Protection ("DEP"), Federal Energy Regulatory Commission ("FERC"), Federal Environmental Protection Agency ("EPA"), other states, etc.) to ensure that any adverse environmental effects of restructuring are minimized. Id., pp. 35-36. The Department found that environmental compliance costs after August 1995 are not "sunk costs," but costs of providing power in the future. Id., p. 38.

The Attorney General agrees with the Department on each of these broad issues. If Massachusetts is to comply with the Clean Air Act emissions limits in the coming years, power plant emissions must be reduced substantially both in Massachusetts and in other states. Coordination among regulatory jurisdictions is critical not only in achieving environmental compliance, but also in facilitating a level environmental playing field for all generating units regardless of age and location. In order to develop a fully competitive market for generation, the Department should not allow recovery of future environmental compliance expenses as though they were "sunk" or "stranded" costs.

To the extent permitted under its statutory authority, the Department should implement a rule that helps the environmental agencies enforce compliance and accelerates the achievement of a level playing field environmentally. The Department should also assist the environmental agencies through its licensing authority. Assuming it has and/or obtains the appropriate statutory authority, the Department should require each applicant/holder of a license to sell retail power in Massachusetts to meet the same air emissions standards. Each applicant/licensee should be required to demonstrate each year that the average emissions rate from its portfolio of coal- and oil-fired generation sources (either owned or purchased) is no higher than the statewide average rate for each restricted air pollutant from all Massachusetts coal and oil plants.[26] This would help to ensure that all retail power sellers here compete on an equal footing environmentally, even if their generation sources are located in areas with less stringent emissions standards. Massachusetts has joined other northeastern states in signing a Memorandum of Understanding ("MOU") to restrict nitrogen oxides ("NOx") emissions. Such licensing requirements also could help to achieve compliance with the Clean Air Act and Massachusetts' commitments under the NOx MOU by providing an incentive for

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The environmental monitoring system discussed below in regard to the independent service operator would facilitate tracking of emissions from all coal and oil sources. The portfolio should only include coal and oil units because other sources of generation such as natural gas, nuclear, hydroelectric, etc. emit much less air pollution.

generators located in areas with less stringent emissions standards to reduce their emissions.

The Department made a specific proposal that existing units operating more than three years after their original retirement dates be required to comply with emissions standards for new generating units. The Department asked whether such a requirement would be feasible, what costs would be involved and how the Department should support the relevant environmental agencies in implementing such an approach. D.P.U. 96-100 May 1 DPU Statement, p. 39.

The Department's proposal would only reduce emissions in the next decade to the extent that coal- and oil-fired plants in Massachusetts have original retirement dates scheduled during the next seven years. Since not very much generation capacity was originally scheduled for retirement during the next few years, the Department's proposal would not do enough to support the efforts of the relevant environmental agencies to protect human health and the environment.

The largest source of utility air pollution is power plants that burn fossil fuels (coal, oil and, to a lesser extent, natural gas). Power plant emissions must be reduced substantially in Massachusetts and in states upwind of Massachusetts in order to protect human health and the environment.

Fossil fuel-burning power plants emit NOx, a primary component of ozone and smog. NOx emissions, both generated locally and transported downwind from other states, will make it very difficult to bring Massachusetts into compliance with 1999 Federal Clean Air Act limits for ozone. Massachusetts needs utilities to reduce their NOx emissions rates for all plants to .15 pounds per million British Thermal Units generated ("lbs/MMBTU") by 2003 in order for this state to meet its commitments under the NOx MOU.

Moreover, fossil fuel-burning power plants are the primary source of sulfur oxides ("SOx") emissions. SOx and NOx contribute to acid deposition and to the fine particulate matter (less than 2.5 microns, the so-called "PM 2.5") pollution that appears to be a primary cause of respiratory health problems in New England. In order to control acid deposition, PM 2.5 and other pollutants, utilities should be required to reduce their portfolio average SOx emission rates for coal and oil-burning plants to .2 lbs/MMBTU by 1999. Reductions could be achieved in a cost effective manner through emissions trading as well as fuel switching, repowerings and retirements.

In addition, reductions in utility emissions of carbon dioxide may be needed to comply with the President's initiative to reduce global warming. A recent study for the Boston Edison DSM Settlement Board found that "CO2 emission reductions may present the greatest challenge for an integrated air policy in New England." Integrating Clean Air Policy to Improve Air Quality and Reduce Pollution Control Costs for the Electric Power Industry, MSB Energy Associates, April, 1996, Vol. 1, p. 15. Utility emissions of toxic metals such as mercury and chromium affect human health and the environment, and the environmental agencies may order emissions limits for them.

Much of the current utility air pollution is from older coal- and oil-fired generating units that have not been subject to the emissions limitations required for newer units under the Federal Clean Air Act. Many of the dirtiest units are located upwind of New England and contribute to our local air pollution. The Attorney General and DEP are attempting to force upwind states to reduce their emissions. In addition, emissions from New England units need to be reduced in order to comply with the Federal Clean Act standards locally and to establish credibility in the battle to reduce emissions from upwind states. To the extent permitted under its statutory authority, the Department should implement a rule that supports the air pollution reduction goals of the relevant environmental agencies.

Limits on air pollution emitted from existing fossil fuel-burning power plants may or may not increase the market price of power, depending on whether there are competitors ready to meet all demand for power without needing to raise prices. In any event, air emission limits can and should be implemented in cost effective ways that make any potential market price increases modest in proportion to the environmental and health benefits that would result. A cap and trade program for NOx emissions, such as the Massachusetts DEP is now considering, would reduce the overall costs of compliance. Retirements, repowerings and fuel switching (e.g., coal and oil to natural gas) appear to be less expensive than retrofitting existing units with emission controls. The study for the Boston Edison DSM Settlement Board cited above concluded that "facilitated retirement of existing power plants and replacement with new, efficient gas-fired plants is an economic means of cleaning up the air." Integrating Clean Air Policy to Improve Air Quality and Reduce Pollution Control Costs for the Electric Power Industry, MSB Energy Associates, April, 1996, Vol. 1, p. 18.

The Department's proposal also would not do enough to achieve the level environmental playing field required for effective competition inside and outside of New England. Again, there is not very much Massachusetts coal and oil-fired generation capacity that had original retirement dates scheduled within the next seven years. Under the Department's proposal, it would be many years before parity in emissions limits is achieved among all plants.

The Department asked whether the role of the independent service operator ("ISO") should be expanded to include the monitoring of generation portfolio emissions to ensure continued progress with federal environmental standards. The Department also asked how this information could be provided in a format useful for relevant environmental agencies.

All coal- and oil-fired generation emissions should be monitored on a "real time" basis, whether it is done by the ISO or another entity. The current portfolio average emissions rate of each generator or aggregator proposing to sell in an area, as well as the percentage of its power generated from clean renewable resources, should be posted on an on-line information network, similar to the electronic bulletin board currently used for gas purchases. Much of the emissions data required is already available through the EPA's Continuous Environmental Monitoring System. An on-line "real time" system would facilitate an important aspect of customer choice: enabling customers to select power based on emissions as well as price (a form of "green choice"). The same emissions information would also be useful to environmental regulators seeking to achieve compliance with state and federal clean air acts.

B. ENERGY EFFICIENCY

The Department found that it is in the public interest to continue to support and encourage the development of the energy efficiency industry in Massachusetts. The Department stated that, as new sectors of the energy services market become competitive, regulatory intervention should be curtailed and eventually eliminated. The Department's primary goal is to eliminate market imperfections where possible, and to mandate utility programs only where market imperfections continue (e.g., insufficient information about energy efficiency, lack of financing options, the inability of low-income customers to purchase energy efficiency measures, and the differing motivations of landlords and tenants). D.P.U. 96-100 May 1 DPU Statement, pp. 64-68.

The Attorney General agrees with the Department on each of these broad issues. The Department should continue to support and encourage the development of the energy efficiency industry in Massachusetts. Where emerging competitive markets will provide particular energy efficiency services at least as well as the current utility programs, the utility programs that provide those particular services should be phased-out gradually. Utility programs should continue to receive regulatory support where there are market imperfections.

Four issues regarding energy efficiency merit further discussion.

1. RETROFIT MARKET BARRIERS

The Attorney General also agrees that the Department should encourage the development of market-driven and market transformation energy efficiency programs. However, the Department may be underestimating the extent to which market imperfections can be eliminated for retrofit applications of energy efficiency. The utility-sponsored retrofit programs have avoided power plant emissions and produced substantial long-term savings for customers since the late 1980s. The Department should move very cautiously in eliminating such successful programs if market imperfections continue. Utilities may need to have more than a "niche" role in providing energy efficiency if market imperfections continue.

2. DISTRIBUTION PLANNING AND ENERGY EFFICIENCY

The Department stated:

> In order to encourage the most efficient use of a distribution system, when there are opportunities to reduce or avoid distribution upgrade costs through distributed generation and targeted demand-side management, a least-cost approach might require a distribution company to locate appropriately-sized generation or demand-side management ("DSM") in distribution-constrained areas.

D.P.U. 96-100 May 1 DPU Statement, p. 41. The Attorney General agrees that energy efficiency will remain an important part of least cost distribution services planning. The so-called "distributed generation" options will take on increased importance as generation is separated from transmission and distribution functions. The Department should continue to emphasize the importance of considering energy efficiency opportunities in distribution company planning.

3. LOW INCOME ENERGY EFFICIENCY

The Department invited comments on whether energy efficiency programs or low-income discounts are a more efficient way to assist low-income customers. D.P.U. 96-100 May 1 DPU Statement, p. 65. Regardless of which is more efficient, this should not be an "either-or" choice. Low-income customers should continue to receive both discounted rates <u>and</u> energy efficiency services. If low-income customers were to receive larger subsidies instead of energy efficiency benefits, they might be no worse off than they are today, but the environmental improvement would still be lost as a benefit to all.

The Department has recognized that there are particular market imperfections that interfere with the provision of energy efficiency services to low-income customers. It should work to see that those barriers are overcome and that, until the imperfections are eliminated, either the utility or some other party provides energy efficiency opportunities no less than exist today.

4. RATE DESIGN AND ENERGY CONSERVATION

Rate design can affect price-driven conservation substantially, but it is addressed only briefly in the Department's May 1, 1996 Proposed Rule. 220 CMR 11.03 (3) (a) (v). Current marginal energy rates have been set in a period of power surplus. If future rates are collected more through fixed charges (customer and demand charges) and less through variable (energy and fuel) charges, as Boston Edison Company has proposed, then customers will not receive the proper price signal to conserve as power supplies tighten. In designing any access charges, the Department should be careful not to increase the percentage of overall rates collected through fixed charges, thereby potentially losing efficient and environmentally-valuable savings from price-driven customer conservation.

C. RENEWABLES

The Department defined renewable energy resources ("renewables") as "non-depletable or naturally replenishable but flow-limited." Proposed Rule, 220 CMR 11.08 (2). The Department stated that renewables have advantages in terms of low environmental impact. D.P.U. 96-100 May 1 DPU Statement, p. 68.

The Department's definition of renewable energy resources in the proposed rule should be revised. Many existing renewables do not have a low environmental impact (e.g., wood chip burners and trash incinerators). While hydroelectric power is renewable and has lower air emissions than fossil fuel power plants, it still has substantial impacts on the local environment. The Department should focus on promoting renewable technologies that have low environmental impacts. Its rule should define "clean renewables" as technologies that harness sources of renewable power such as wind turbines, photovoltaics ("PV") and biomass gas that have low environmental impacts.

The Department stated that renewables should have a meaningful opportunity to compete in the emerging energy market. The Department therefore proposed that "a low (e.g., 1 mill per KWH), non-bypassable charge on distribution services" be collected and "used to foster competition in resources that cost only slightly more than the premium customers are willing to pay to purchase renewables." D.P.U. 96-100 May 1 DPU Statement, p. 69.

The Attorney General strongly agrees with the Department that Massachusetts should promote the development and commercialization of clean renewables and the related sales infrastructure. Clean renewables (plus future fuel cells using hydrogen) are likely to be highly valuable as power sources offering both low environmental impact and more diversity of energy resources. If nuclear or dirty fossil fuel units are retired early, then resource diversity benefits would become even more valuable. Indeed, clean renewables development could become an essential part of our energy future. The Department should encourage the development of various clean renewables technologies, to maximize resource diversity.

Clean renewables (e.g., roof-top PV systems) have other advantages related to their being located around the distribution system: 1) they are not subject to as much line loss; 2) they may help avoid transmission and distribution costs; and 3) they provide greater "load diversity" than central generating stations, thus reducing the whole system's need for capacity reserves. As recommended above in regard to energy efficiency, the Department should require distribution companies to plan properly to provide distribution service at least cost. This means that distribution companies would be required to consider clean renewables' advantages in terms of resource diversity, load diversity, environmental impacts and line loss savings.

The Attorney General urges the Department to adopt a portfolio approach for clean renewables rather than a direct funding mechanism. The Department should require that all sellers of power to retail customers in Massachusetts must obtain the following percentages of their power from clean renewables in the following years: at least one percent by 1999, at least two percent by 2002, at least three percent by 2004, and at least four percent by 2006. As with many aspects of electric utility restructuring, the Department may need to seek additional legislation for this portfolio approach to the extent that its current statutory authority is insufficient. Whatever means of support the Department adopts should ensure that clean new renewables technologies are commercially available in Massachusetts as soon as possible.

The Department asked whether customer-generated renewable power should be valued at the market price or the total retail rate. Customers should continue to receive the total retail price for power they generate from a renewable source. Otherwise, there would have to be a second meter and a second calculation of bills. The current system of net billing through a meter that runs both forward and backwards is the most efficient way to price the renewable power generated by customers. Total retail price is also appropriate, given the customer-owned renewables' advantages in terms of energy resources diversity, load diversity, environmental impacts, line losses and savings for additional metering and billing.

As part of electric restructuring, the Department should continue to support environmental improvement by implementing rules that will help the relevant environmental agencies to reduce air emissions, increase energy efficiency and promote the development and commercialization of clean renewable technologies.

. CONCLUSION

WHEREFORE, for the all of the foregoing reasons, the Attorney General submits that the Department should modify its proposed regulations as recommended herein.

RESPECTFULLY SUBMITTED
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Dated: May 24, 1996

COMMONWEALTH OF MASSACHUSETTS
before the
DEPARTMENT OF PUBLIC UTILITIES

Notice of Inquiry/Rulemaking Establishing The Procedures To Be Followed In Electric Industry Restructuring By Electric Companies	))))))	**D.P.U. 96-100**

SUGGESTED HEARING QUESTIONS FOR PUBLIC UTILITY COMPANIES

The Department indicated that it desired suggestions as to hearing questions in this proceeding. The Attorney General recommends that the Department should ask the following as questions or record requests:

1. Please identify each purchased power contract that the Company currently has in effect. Please also provide the following information for each contract:

   (1) the initial date that power is supplied under the contract;
   (2) the expected end date of the supply of power under the contract;
   (3) the actual capacity and energy supplied for each year to date;
   (4) the future expected annual capacity and energy supplied under the contract;
   (5) the actual annual fixed costs per kw and per kwh for each year of the contract to date;
   (6) the future expected annual fixed costs per kw and per kwh for each year of the contract;
   (7) the actual annual variable costs per kwh for each year of the contract to date;
   (8) the future expected variable costs per kwh for each year of the contract;
   (9) the actual transmission cost components per kw and per kwh associated with the contract; and
   (10) the pages of the contract (and all amendments) which provide for assignment, termination, severability, and buy outs along with the pages providing for the obligations under each.

2. Please identify each of the Company's generating units which it owns directly or has life of the unit contracts for. For each unit (on an individual basis for each unit of a multi-unit station), please also provide the following information:

   (1) the original on line date of the unit;
   (2) the expected retirement date of the unit;
   (3) the estimated removal costs of the unit;

(4) the estimated salvage value of the unit;
(5) the book value of the land associated with the unit;
(6) the market value of the land associated with the unit;
(7) the unit's capacity both summer and winter;
(8) the station capacity requirements both summer and winter;
(9) a ten-year history of the heat rate for both summer and winter on each fuel type;
(10) the DPU heat rate goal (by season);
(11) a ten-year history of the amount of each fuel type burned and the percent of total (on a BTU basis);
(12) a ten-year history of the rate paid for each fuel type;
(13) a ten-year history of the monthly output;
(14) a description the fuel/transportation contracts with all important terms thereto; and
(15) an indication whether the Company considers the unit to be a base load unit, an intermediate unit, a peaking unit, or some combination thereof.

3. Please provide a complete and detailed description of the risk management techniques that the Company uses (plans to use) to manage its power supply, power contracts, and fuel contracts. Please also provide a complete and detailed description of the methodology that the Company uses to determine the mix of long-term commitments, short-term commitments, and spot purchases used to meet the Company's load requirements.

4. Please provide a calculation of the annual revenue requirement on an actual historical basis for the last five years and on an expected basis for each year thereafter until the unit's retirement for each of the Company's generating units which it owns directly or has a life of the unit contract for. For each of the units please provide an itemization of the cost components for the annual revenue requirements including at least the following items:

(1) Plant Balance;
(2) Plant Additions and Retirements;
(3) Accumulated Depreciation;
(4) Materials and Supplies Balance;
(5) Accumulated Deferred Income Taxes;
(6) Unamortized Investment Tax Credits;
(7) Customer Advances, Deposits, and Unclaimed Funds Balance;
(8) Depreciation Expense;
(9) Amortization Expense;
(10) Fuel Expense;
(11) Purchased Power;
(12) Non-Fuel O&M;
(13) Taxes Other Than Income Taxes;
(14) State Income Taxes;
(15) Federal Income Taxes;
(16) Investment Tax Credits;
(17) Overheads Costs Along With Allocators;
  (a) Administrative and General Expense;
  (b) General Plant (Depreciation, Return, Income Taxes, Property Taxes);
(18) Other Revenues;

(19) Cost of Capital; and
(20) Annual kwh Output.

Please also provide all of the assumptions that the Company used to determine the revenue requirement and any of its individual components.

5. Please provide the following information for each of the Company's generating units:

(1) the Company's current estimate of the cost to decommission in current dollars including all of the workpapers, calculations, formulas and assumptions used to make the estimate;
(2) the Company's estimate of the cost to decommission in future dollars (at the point of commencement of decommissioning) including all of the workpapers, calculations, formulas and assumptions used to make the estimate;
(3) the decommissioning cost estimate used in the Company's last base rate case filing;
(4) the current balance in the Company's decommissioning trust fund including an itemization and quantification of the different investment vehicles currently employed; and
(5) a complete and detailed description of the trust fund investment policy regarding the amounts and types of investments that the funds can be invested in.

6. Please identify each deferred operations and maintenance expense item that the Company is deferring on its books as the result of FASB Statement 71. For each item please also provide the following information:

(1) the current deferred amount on the Company's balance sheet at year-end 1994 and 1995;
(2) the expected recovery period; and
(3) the expected annual recovery amounts.

7. Please provide the following information regarding the Company's Post-Retirements Benefits Other Than Pensions:

(1) the year-end amount of total accumulated benefit obligation (vested and non-vested);
(2) the year-end amount of total projected benefit obligation (vested and non-vested);
(3) the market value of the year-end trust fund assets;
(4) the annual trust fund contribution for each of the last five years;
(5) the expected annual trust fund contribution for each of the next five years;
(6) the annual cost recorded on the Company's books for each of the last five years; and
(7) the expected annual cost to be recorded on the Company's income statement for each of the next five years.

8. Please provide the following information regarding the Company's Pension Benefits:

(1) the year-end amount of total accumulated benefit obligation (vested and non-vested);
(2) the year-end amount of total projected benefit obligation (vested and non-vested);
(3) the market value of the year-end trust fund assets;
(4) the annual trust fund contribution for each of the last five years;
(5) the expected annual trust fund contribution for each of the next five years;
(6) the annual cost recorded on the Company's books for each of the last five years; and
(7) the expected annual cost recorded on the Company's income statement for each of the next five years.

9. Please itemize and quantify the components of the Company's current intangible plant balance. Please also provide a complete and detailed description of the methodology that the Company is using to recognize the cost of each item over time including the annual expense amounts and the total period of recovery.

10. Please itemize and quantify the current balance of unrecovered cancelled plant costs on the Company's books. Please also provide the annual amount of recovery for each cancelled plant currently included in the Company's rates.

11. Please provide a profile of the Company's current base, intermediate, and peaking supplies. Please also provide a profile of the Company's current ten-year forecast of those individual supplies.

12. Please provide a profile of the Company's current demand requirements for base, intermediate, and peaking load. Please also provide a profile of the Company's current ten-year forecast of the demand requirements for those individual supplies.

13. Please provide the Company's current ten-year forecast of the market rates for the capacity and energy components of base load, intermediate, and peaking capacity for both five- and twenty-year contracts.

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Notice of Inquiry/Rulemaking Establishing The Procedures To Be Followed In Electric Industry Restructuring By Electric Companies	)))))	**D.P.U. 96-100**

SUGGESTED HEARING QUESTIONS FOR THE NON-UTILITY GENERATORS

The Department indicated that it desired suggestions as to hearing questions in this proceeding. The Attorney General recommends that the Department ask the following as questions or record requests:

1. Please provide the following information with respect to ownership of each project:

    (a) the name and location of the project;
    (b) the identity of project owner and legal structure of owner (company, partnership, etc.), and state of organization;
    (b) the names of all general and limited partners;
    (c) the name of the lessor if the project is financed through a leveraged lease;
    (d) a history of changes in ownership including the identity of all changes in ownership, or control of a general partner or owning company, since commencement of project operations;
    (e) the name of any entity holding an equity interest in the project that constitutes an electric utility, electric utility holding company, or any subsidiary thereof, including the percentage of such interests as compared to all equity interests.

2. Please provide the following information with respect to financing of each project:

   (a) a list of all current loan agreements with respect to the project, identifying the type of each as term loan agreements, subordinated debt agreements, vendor credit agreements, etc..
   (b) for each loan agreement, provide the following information:
      (1) the identity of the lender;
      (2) the initial loan amount at time of project completion;
      (3) the amortization schedule;
      (4) the current outstanding loan amounts;
      (5) the remaining amortization period;
      (6) the periodic interest rates;
      (7) the required operating reserves;
      (8) the priority of security of each creditor;
      (9) the debt obligations secured by the project assets that have been retired, including dates of issuance, retirement, and principal amount.
   (c) identify all allocations of income, gains, losses, deductions, and credit, and distributions of cash (including any royalties, finders fees, or development fees) as of closing on construction financing for the Project, and for each year thereafter [Note: This response should make clear how, and to what extent, holders of equity in the Project have realized gains or losses from the Project].

3. Please provide the following with respect operation of each project:

   (a) the installed gross capacity;
   (b) the installed net capacity;
   (c) the dates upon which the project commenced selling its net electric output to the purchasing utility;
   (d) if power sales rates are a function of hourly output, identify the rates applicable to different levels of hourly output for 1995;
   (e) the actual monthly electric generation (net and gross), expressed in kilowatt-hours since commercial operation through the first quarter of 1996;
   (f) the names of all purchasers of such generation;
   (g) an estimate of the monthly output for each year from 1996 through the expiration of the contract;
   (h) the actual monthly thermal energy provided by the project to thermal energy users (if applicable), expressed in kilowatt-hours since commercial operation through first quarter of 1996;
   (i) an estimation of monthly thermal output for 1996 through the expiration of the contract.

4. Please provide the following with respect to each project's fuel supplies:

   (a) the primary project fuel including the annual average percentage of project energy input for each year of project operation to date;
   (b) the other fuel(s) used including annual average percentage of project energy input for each year of Project operation to date.
   (c) Primary Fuel Information:
      (1) the current heat rate by season of the project utilizing primary fuel (Btu/kWh) at standard operating conditions (please define);
      (2) summaries of (i) prices paid to date for project fuel; and (ii) projections of annual project fuel costs through the expiration of the contract;
      (3) copies of current fuel supply contracts;
      (4) the method of transporting the fuel to the project and, if applicable, copies of any transportation contracts;
      (5) the fuel storage capacity and annual average fuel storage costs to date;
      (6) an explanation of how the project manages risks associated with its primary fuel supply. [Note: This discussion should include an explanation of long and short-term supply contracts, fuel storage techniques, and the results of any current fuel studies relied upon.]

5. Please provide the following financial statements for each year of operation of the project through 1995:

   (a) Income Statement;
   (b) Balance Sheet;
   (c) Statement of Cash Flows; and
   (d) Statement of Retained Earnings

   Please also provide this information on a diskette in Lotus 1-2-3, Release 4 spreadsheet format.

6. Please provide the projections (including all assumptions used to make such projections) of the following financial statements for each year of operation of the project from 1996 through to the expiration of the project contract:

   (a) Income Statement;
   (b) Balance Sheet;
   (c) Statement of Cash Flows; and
   (d) Statement of Retained Earnings

   Please also provide this information on a diskette in Lotus 1-2-3, Release 4 spreadsheet format.